Cinergy Corp. Position Paper on Output Based Allowance Allocations

For

Updating Output Emissions Limitations Workgroup

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Summary

Historically emission performance standards and allowances allocations for electric generating units have been formulated using energy input (e.g., pounds of NOx or SO2 per million Btu of heat input from the fuel used). The recent NOx SIP Call also allocated individual state budgets on a heat-input basis. Recently some parties have advocated to EPA an "output-based" allowance allocation. Such a process would be based upon the amount of electricity generated (kWh, output) rather than the energy input to a boiler or other source (Btu heat input). Proponents of output-based emission standards believe that this approach provides an incentive for more efficient energy conversion, and to encourage cleaner forms of generation. As such, EPA has organized the "Updating Output Emission Limitations Workgroup" to solicit guidance on potentially updating the NOx allowance allocation process.

Cinergy supports the timely attainment of clean air standards, but believes that policymakers must choose the most constructive, cost effective and flexible means of achieving these goals. To achieve these goals, Cinergy advocates the following:

- Environmental programs and goals such as the NOx SIP Call should be formulated on sound environmental policy considering environmental benefits and the cost of different compliance options.
- Industry must be allowed to utilize market forces such as trading to implement these goals in the most cost-effective fashion.
- Electric deregulation will force companies to seek increased energy efficiency.
- EPA should support regulatory reform such as streamlining NSR requirements. In particular, NSR reform could greatly reduce the regulatory restrictions that impede utilities from making beneficial improvements that would reduce costs to customers and deliver benefits to the environment.
- Adoption of output based standards should not subsidize specific non-combustion sources of generating.

To the extent that a process for output based allocation of emission allowances is developed, Cinergy has specific recommendations that should be incorporated into any output based system. These recommendations are summarized below. Additional detail is given later in this document.

1. Output based allocation strategies for any specific pollutant must include only those sources requiring allowances for compliance purposes. Including any other sources such as nuclear and hydroelectric generation would constitute a direct subsidy of those sources. In addition, this form of subsidy would also result in a higher overall cost of compliance because the most cost efficient controls would not be utilized.
2. An output based allocation methodology must not penalize sources for the operation of control equipment needed to reduce emissions. Calculating output based on gross generation would accomplish this objective.

3. Gross output is the most practical parameter for expressing emissions on an output basis. This parameter is already an input to most EGU CEMs systems. It generally would require monitoring in only one location per generating unit. Net output is not always directly monitored. An attempt to use net output would increase the number of inputs to the CEMs and Data Acquisition System (DAS) and require further changes to software.
4. Many facilities have multiple boilers and/or turbines operating in a common system. These sources should be given the flexibility to express output from these units together in common. Sources would sum the emissions from all effected boiler(s) and divide it by the gross electricity produced by all electric generator(s) served. This solves the problem of allocating electricity from specific turbines to specific boilers.
5. Facilities generating process steam for uses other than electric generation should convert this output to equivalent electric power. A source would measure the total mass flow, temperature and pressure of process steam, as well as the enthalpy of the returned and/or make up condensate. A source would then calculate the amount of heat transferred to the process steam and convert it to an "equivalent electric power" based on 3,413 Btu/kWh. This output would be added to the actual electric output.
6. Sources using a portion of the steam generated to operate process equipment other than electric generators should also convert this work to an equivalent amount of electric power. Since work performed is not directly measured, it should be calculated from other process parameters. For example where process steam powers a compressor, the work performed should be calculated based on the flow, and changes in temperature and pressures of the fluid transported (not the steam used to power the equipment). This work is then converted to an equivalent amount of electric power.
7. For some sources the additional costs for monitoring the energy used for process steam or for any mechanical work other than generating electricity is not trivial. To install all the additional instrumentation could be cost prohibitive. Some sources may decide that the cost burden is not worthwhile. As a result, they should be allowed to "opt in" to monitoring the portion of their output that goes to process steam or other forms of work.
8. Any additional burden imposed on sources should be minimized and should prevent adverse impacts on operations. Existing CEMs monitors can be removed from service without impacting operation of the unit. Current and potential transformers and other equipment used to measure electricity generation are extremely reliable. There should be only minimal maintenance requirements imposed on these devices because they are connected to high voltage transmissions lines and maintenance online will interfere with unit operation.
9. It will take several years for promulgation of guidance and/or rules, and the acquisition, installation, and testing of equipment installed to support output based standards. Once the needed equipment is installed, it is necessary to accumulate sufficient data to develop a representative baseline. Any consideration of applying an output based allocation process should wait until this baseline can be developed.

State Budgets and Emission Rates for Input and Output-Based Approaches

Before fully discussing output based allowance allocations, one must appreciate the magnitude of the changes it will institute. EPA estimated the SIP Call's cost of utility NOx reductions to be $2,000 per ton or less. Industry counters that some emissions will have to be reduced at a cost of $4,000 per ton or more. The economic impacts of these decisions become clear when considering the how allowances could be redistributed. Within specific states, the decision to use input based or one of the different output allocation methods will not change the total amount of pollutants that would be emitted. It will redistribute the financial burden individual stakeholders must endure.

In its final 22-state NOx SIP call, EPA considered how State NOx budgets would be changed using the output approaches suggested by stakeholder comments. It calculated State budgets using output approaches. It used generation data from the Energy Information Agency (EIA) was available for utility and non-utility generators. In the attached Table 1, Column 2 presents the revised budgets based upon heat input and the revised growth factors. Column 3 shows output-based budgets, using electric generation from all sources including nuclear and hydroelectric. Column 4 shows output-based budgets, based on all electrical generation except nuclear generation. Column 5 shows output-based budgets using electrical generation from fossil fuel only.

EPA then calculated the effective NOx emission rate for each State in terms of lb/mmBtu, assuming that the entire electricity generation component of the budgets, were allocated to the electric generating units (EGUs). EPA wanted to see if the effective NOx emission rate would be too low to be feasible without participation in an interstate NOx emission-trading program. The EPA found that under output-based State budgets from all generation sources, three States would need to impose an effective emission limitation of 0.10 lb/mmBtu or less on their fossil-fueled electricity generators (see Column 3 in Table 2 below). One State would need to impose an emission limitation of 0.07 lb/mmBtu. Such a low effective emission limitation may not be technically achievable in a State without interstate allowance trading. In contrast, the Agency found that it was feasible and cost-effective to make reductions even without an interstate NOx trading program under an input-based State budget calculated using a uniform NOx emission rate of 0.15 lb/mmBtu. This example considers that sources will just meet the proposed budgets. In fact, actual emissions and emission rates could be less than those indicated. Sources must operate with a safety margin. In addition, States may hold allowances back for future new sources. Therefore the effective emissions rate would be even lower.

Use of Fossil Generation vs. Total Generation from All Sources

A key decision in formulating an output based allowance allocation program is which sources are included in the allocation. The NOx SIP Call developed budgets from total fossil energy heat input of all electric generating units for the years 1995-1996. Other sources such as nuclear and hydroelectric were not included. This total energy input was then increased using growth factors to a 2007 baseline. Under an input methodology, sources would receive a prorated share of allowances based on their share of the budget. The appropriate method for implementing an output based allocation methodology would give allowances to only combustion sources based on the amount of electricity generated, rather than the energy input. For example a specific source in the baseline years used 1.0% of the total amount of the state's thermal energy, but because of higher efficiency of the unit, actually generated 1.1% of the state's total electricity. Under an output based allocation methodology, that source would receive 1.1% of the total allowances and not 1.0% like it would receive under an input allocation.

Some parties have advocated to EPA that other sources of generation should be included in the allocation process, specifically nuclear and hydroelectric. These sources do not need for allowances because they do not generate emissions of NOx, or SO2. However including their generation in the total would give them a share of the allowances. Because hydroelectric and nuclear generating units have no compliance use for them, units must sell these allowances to realize any value. Permanently holding or retiring these allowances would not be logical. The NOx SIP Call have imposed large scale NOx reductions and expense on coal-fired electric generators and other fossil fired sources. As such, allowances allocated to these sources cannot be claimed to be subsidies. However giving allowances to non-emitting sources obviously would be a subsidy.

Giving allowances to existing hydroelectric and nuclear is not an incentive to build and operate new, cleaner generation. These are considered "sunk" construction costs. Rewarding them with additional allowances will not change those decisions. Constructing a hydroelectric power plant for example is primarily an artifact of geography. Rewarding past decisions is no guarantee of similar future decision making.

Ambient Air Quality Considerations

Some environmental groups see implementation of output-based emission standards as a method of drastically reducing NOx emissions to accelerate the attainment of the ozone NAAQS. They also see it as a way to force utilities to move away from coal-fired boilers to other generation sources (by increasing the cost so that other fuels or methods of generation become more competitive). On the contrary, implementing an output based allowance methodology on a region wide basis will not necessarily improve air quality.

Switching to Output-based State budgets will result in a different geographic distribution of allowances than would occur using the original input based budget allocation. In some states, the effect of adding nuclear generation in particular is very dramatic. As seen in Table 1, the states of Connecticut, New Jersey, New York, and Rhode Island will see a significant increase in the number of emission allowances using an output based allocation. These states currently have existing concerns with ozone non-attainment. Increasing the amount of allowances will have one of two results. First, the states could experience an increase in NOx emissions in areas currently with more severe ozone concerns. Extensive air quality modeling has shown that reductions of NOx in the close proximity to non-attainment are more effective in attaining the ozone standard than reductions hundreds of miles distant. Clearly this option is not acceptable.

Secondly, if sources in these areas were not permitted to use these additional allowances, they would be forced to sell them or retire them. If these allowances were sold, the sellers would receive an economic benefit at the expense of the purchaser to which they would otherwise be allocated. Because NOx allowances could be issued at a zero cost basis, the transaction could be taxable. If the excess allowances above what a source could utilize were retired, then the total pool of allowances would be effectively reduced. This would drive up the compliance costs for all other sources.

The Economic Issues Associated with Output Based Allocations

Allocation of allowances to non-NOx-emitting units, such as nuclear, and hydroelectric, will make compliance more difficult for fossil fuel burning sources because fewer allowances would be allocated to them. As a result, the total cost for a NOx emitting source that would have to buy these allowances, plus install control equipment would be higher. Selling allowances could be a taxable transaction, which will increase the total cost. Companies receiving extra allowances because of their non-combustion generation could decide to use them internally. As an example, utility “A” has a large amount of nuclear generation and decides to invest primarily in SNCR technology for NOx removal. As a result they reduce their fossil emissions rate to about 0.25 lb/mmbtu as opposed to the SIP Call’s 0.15 standard. They avoid installing some relatively cost effective SCR projects. Utility “B”, faced with a lower number of NOx allowances, would have to meet a system average significantly below 0.15 lb/mmbtu. As a result, they would need to install additional SCRs. The additional SCRs will remove NOx at a much higher cost per ton than the SCRs avoided by company A.

Some would argue that utility “A” would build extra SCR capacity and sell the surplus allowances. This reasoning has several problems. First, if allowances are issued on a zero cost basis, taxes could drive up the sale price, as companies would need to recover the taxes. Secondly, companies would need to receive an acceptable profit margin above what they consider the internal value of the allowance. Building an SCR above and beyond what is needed for compliance is an investment with significantly more risk. As a result, they would expect a much higher return on the investment. This also would increase the price they would need to receive on the sale of an allowance. Finally in the current pre-deregulation environment, most utilities are striving to minimize additional capital investments. In other words, many companies will not want to make capital available for these types of investments. All of these concerns will increase the cost of compliance with an allocation that includes non-combustion generation sources.

Some urge allocation of allowances to nuclear and hydroelectric units to support “non-polluting” sources. This is asking other power sources to finance these owners in decisions they made long ago. Generating units are dispatched based on operating costs. Because of low fuel costs for nuclear hydroelectric units, they are normally base-loaded with a high capacity factor. Giving them allowances will not likely by itself increase output. Even if increased fossil output displaces these sources, (which is unlikely due to capacity and transmission constraints) Title IV and the NOx SIP Call have capped SO2 and NOx emissions. The amount of emissions per unit of electricity must decrease so the cap is not exceeded.

A fossil fuel only output based allocation process would encourage new more efficient sources. For example a new natural gas combined cycle unit would benefit for two reasons. First, the amount of thermal energy required to make a kWh of electricity is significantly less. Second, the amount of emissions generated by the combustion turbine per unit of energy input is significantly less using the currently available forms of combustion and post combustion control technologies. Therefore using an output based allocation including only fossil fuel combustion sources, these types of units would receive the greatest benefit compared to other options.

How Electricity Is Measured In Power Plants

The total amount of electrical power made by a generating unit is called gross generation. A small percentage of the electricity generated in a facility is used to operate the electric equipment within the facility. This portion of output is called auxiliary electrical power (aux. power). The rest travels to the electrical grid and is supplied to customers. The sum of net generation plus auxiliary power equals gross generation. Generators make three-phase power. This means there are three power leads coming from each generator plus a neutral return path. Each lead or phase when connected to the neutral wire is capable of delivering electric power. Larger electric loads use all three phases to obtain greater efficiency. The total electric power delivered by a generator is the sum of all three phases. To describe all the intricacies of power measurement is beyond the scope of this paper. However, the basics are that the voltage and current flow across each phase must be measured individually and then summed together in order to get the total.

Power is normally made at voltages between 20,000 and 28,000 volts. The generator step up transformer increases the voltage to 138,000 volts or higher to gain transmission efficiencies. These voltages are too high for direct measurement. A Potential Transformer (PT) is installed on each phase of a generator output to step the voltage down to a more usable level, typically use 120 volts. That signal is used as part of the power calculation. The PT is a highly accurate device (typically ½% or better) that transforms the high voltage to low voltage. The ratio of wire coils in the “high side” vs. the “low side” determines what voltage the attached instrumentation operates at. This number of coils, or turn ratio is fixed and cannot change. The second component needed to calculate power generated is the amount of current flow as measured in amps. To measure amps on a high voltage line, a Current Transformer (CT) is used. The current in the power line induces a current flow in the CT. That current is measured and used in the power calculation. As with a PT, a CT is a highly accurate device with a fixed number of wire coils. These devices require little routine maintenance.

The power developed by a generator is calculated from the voltage (volts), current flow (amps), and the phase angle between them (power factor). For power calculation, the voltage and current for all three phases is needed. These six inputs go to one signal processor, which calculates total power. Because the instruments are connected to high voltage power lines, they can not be easily serviced while the unit is operating. Sometimes these devices are part of generator protection circuits. In case of a fault or other electrical problem, these devices prevent equipment damage by shutting the unit immediately. Also, the signal processor and inputs are difficult to disconnect on line without interrupting operation or even shutting the unit down. Fortunately these devices are extremely reliable and require little routine maintenance or calibration to maintain their high accuracy.

The CEMs and other functions in the generating unit use the instrument signal showing unit load. Many of these functions regulate the steam turbine, boiler, and pollution control equipment. Some devises could be adversely affected if the equipment were taken out of service for calibration while the unit is operating. Because of the concerns with measurement of unit power, Cinergy recommend that no requirements be placed on these devices while the unit is operating. Instead, any verification of operation should be accomplished during a unit's routine scheduled maintenance outage that occurs every one to three years. To require maintenance activity at any different timing would require shutting the unit down, create a considerable cost, and possibly create additional emissions.

Gross vs. Net Electrical Output

The previous discussion was an example for gross electrical output of a generating unit. Not all units directly measure net generation. At many Cinergy generating units, net generation is determined by first measuring the total amount of auxiliary power used and subtracting it from gross generation. To measure total auxiliary power, generating stations measure power flow through each of multiple pathways. The same methodology and instruments are used. However because of the larger number of flow paths, the total number of instruments needed increases. Net power from a unit can only be quantified before it merges with that of other units in the transmission system. At that point it becomes indistinguishable from that of other units. As a result, measuring net power from a unit at a customer's location is not practical either.

The top uses of auxiliary power in power plants are pollution control devices, cooling systems, and fuel handling. Pollution control devices consume large amounts of power. For example a flue gas desulfurization unit (FGD) increases auxiliary power usage by several percent. This power operates the additional fans, pumps and other processing equipment required by the scrubber. The NOx SIP Call will require utilities to install large amounts of SCR and other NOx control devices. These units will require additional power for fans, chemical handling and injection equipment. Additional energy is also used for the fans and pumps associated with cooling towers. These towers were often an additional environmental control burden placed on the facility after initial design. Cooling towers are required of many generating facilities to prevent thermal discharges (thermal pollution) to water bodies surrounding the plant. Other pollution control equipment often associated with power plants includes electrostatic precipitators for particulate control, and various wastewater processing equipment. These devices provide environmental benefits, but detract from the power available to customers.

An output-based emission standard based upon Net electrical output disadvantages a facility for the differences in auxiliary power requirements for in-plant systems (fuel handling equipment, pollution control devices, cooling systems, need for winter heating and other energy consuming devices necessary for plant operation). For example, a coal unit generally requires about an additional five percent of station gross output (at full load) for station operation than a conventional gas unit due to differences in power consumption for fuel handling and current emission control systems. A Gross output-based emission standard would reflect emissions from the total electric generation irrespective of the amount of generation that is available to be supplied to the customer. To this extent the Gross output-based emission standard does not distinguish between gas-fired and coal-fired units as to differences in power consumed for other needs such as environmental control equipment in the generation process.

An alternative output-based emission standard could be based upon the Net electrical output rather than the Gross output. An output-based emission standard based upon Net electrical output from the generating unit considers only the electricity that leaves the plant, and is sent to the transmission grid. A Net output-based standard would lead to additional emission control requirements and penalize units that already have significant environmental control systems that consume part of the unit's output. Use of Net output could incentivize generation from coal-fired plants without scrubbers, selective non-catalytic reduction, cooling towers and other environmental control equipment.

Promoting Energy Efficiency by Utility Commissions and Market Forces

Some state an objective of an output-based standard is to encourage more energy-efficient electric generation. The presumption here is made that utilities would be encouraged to design and operate electric generating units with low heat rates (higher efficiency) to achieve the standard. In general, maintaining, or improving efficiency has been a standard utility practice in the past without the imposition of an output-based standard. In most cases, regulatory commission guidelines and/or evaluation through fuel cost audit proceedings forces more efficient operation.

Of the total production cost of electricity, about 80% are fuel cost. Any business that does not actively and aggressively minimize this large a portion of its costs will ultimately find itself out of business. This force alone drives power generators to the highest level of energy efficiency. Minimizing fuel consumption directly translates into lower production costs and lower emissions. This lowers production cost, increases profitability, and benefits to the environment through lower fuel use and emissions. In deregulated utility market, even without an output-based standard, efficient design and operation of utility boilers will be as or more important to a company’s interest.

There are those that believe that deregulation and increased utility competition will increase the utilization of what some consider “dirty generation” from older coal fired power stations. This opinion is a narrow one at best because EPA capped national SO2 and 22-state ozone season NOx emissions. <u>No matter how much power is made, the total emissions can not exceed these caps.</u> Market based cost-effective opportunities to improve efficiency will be taken with or without output-based standards.

Output Based Standards Will Not Materially Effect the Efficiency of Existing Generating Units

It must be recognized that plants operating on the Rankin thermodynamic cycle have reached an effective limit in their efficiency. The state-of-art power plant operates with a supercritical cycle with main and reheat steam temperatures of approximately 1000 degrees Fahrenheit. As a result, existing units have limited potential for improving efficiency beyond the design conditions. These conditions govern the overall cycle efficiency of the unit, and have not changed appreciably in 30 years. For example, the available materials of construction limit steam temperatures and pressures. These are fixed at the time of design and construction. In addition, with the imposition of additional control equipment such as scrubbers, selective catalytic reduction, cooling towers, etc., total unit auxiliary load increases. These cause overall cycle efficiency to decrease.

The design and operation of low heat rate units is only a part of the equation that establishes whether an output-based standard would be effective in achieving improved energy- efficient electric generation. Utility systems normally prioritize the dispatch of individual units based upon the most economic generation. The unit dispatch cost is a function of both the heat rate and the fuel cost. It also considers all other costs including environmental compliance. After fuel, environmental compliance is typically a unit’s next largest cost. Overall fuel efficiency greatly affects dispatch order. A newer supercritical unit will usually be dispatched ahead of an older, lower pressure unit with lower steam temperature. In addition, units must accommodate the daily fluctuations in load demand.

Utility generating units are designed to operate most efficiently at or near full load capacity. This efficiency is for the most part, dictated by the laws of thermodynamics. At lower loads, some equipment does not operate as efficiently. Further, some cyclic units, such as gas turbines, are only brought on-line sporadically rather than on a daily basis. Base- loaded units operate most of the time at near constant loads while cyclic units may operate from completely off-line to full-load to satisfy transient system demands. The most efficient units (as determined by the combination of efficiency and fuel cost) operate at “base load.” This allows these units to operate most or all of the day at their most efficient load point, while less economically efficient cyclic units follow the transient load demands of the system. The cyclic units are only called upon for use during a relatively short period of the day to meet “peak” energy demands. It is important to emphasize that cyclically loaded units which follow load demand requirements during seasonal and daily peaks do not operate at their highest efficiency, but rather operate as efficiently as possible given the unit duty requirements. In short, their use is a part of allowing the system to meet customer demand as efficiently as possible.

It should also be pointed out that characteristics of the various utility systems differ as well. Systems may be summer or winter peaking, or to some extent both; may exhibit differences in the ratio of daily peak to base load; and may have different duration of peak seasonal loading as well. These system operating differences, as well as differences in the character of generating units, contribute to the overall system efficiency differences between the various systems. In summary, each of these conditions describes the environment in which a generating unit must operate. Electricity generation is unique among all other products modern industry produces. It must be produced and delivered at exactly when the customer wants it. There is no effective technique for storing electricity.

NSR Reform to encourage additional efficiency improvements

Some contend that output-based approaches will encourage improved efficiency over time. However another regulatory initiative could actually create more powerful disincentives to utilities considering efficiency improvements. This is the proposed New Source Review ("WEPCO") rule revision. Rather, facilities should be encouraged to make improvements that would increase efficiency while generating benefits to the environment. With sources operating as part of cap and trade programs, EPA has an opportunity to improve the existing and onerous process to facilitate increased efficiency and deliver environmental benefits. Cinergy has provided extensive comments to the agency on this topic. A copy of these comments has been provided for reference.

Facilities with multiple boilers and or turbines

Many facilities have multiple boilers and/or turbines operating in a common system. This practice exists for a number of reasons that include reliability, state of technology, and increased demand for production. Using current methodology, the emissions from boilers are measured on a unit by unit basis. Under current CEMs procedures, operators have the flexibility to report output from these boilers in either power or steam generated. For example, consider a case of system having two boilers and one steam turbine-generator. Each boiler output is measured in pounds steam flow per hour, while the generator output is measured in kilowatt-hours. Because the steam flow, temperature and pressure from each boiler can vary, it is not directly and simply obvious how much of the total electricity coming from the generator is attributable to each boiler. Other configurations could include a single or multiple boilers supplying two or more steam turbines.

With more devices involved, the complexity of assigning generation to specific fuel consumption becomes more and more difficult. The end result of expressing output in terms of pound of pollutant per unit of electricity produced quickly becomes nearly unworkable. Clearly a system of this complexity is confusing and puts an unreasonable burden on the operator as well as the regulator. A very simple and elegant solution would be to group all the connected components together as one large system. Thus to determine output, the total amount of pollutants from the individual boilers would be summed together as would the total amount of electricity produced. This completely eliminates the problem of allocating electricity from specific turbines to specific boilers.

Cogenerating Facilities Generating Process Steam And Mechanical Work

Some facilities generate process steam for outside uses in addition to generating electricity. Understanding the thermodynamics of the Rankin power cycle used by steam electric generating units shows there is a large amount of thermal energy that cannot be recovered in the power generation process. Some of this energy can be recovered and used by other industrial sources through a cogeneration process. This is the basis of a district heating system that also generates electricity. The end result is a combined process that is more efficient than the two individual processes operating separately.

When regulating a cogeneration process on an energy input basis, it is rather simple to evaluate performance, because one is not concerned with the amount of process steam and electric power that is generated. However, when evaluating a unit on an electrical output basis, one must convert the thermal energy transferred to process steam into an equivalent amount of electric power. One proposal is to convert this energy using the thermal equivalent of a kilowatt-hour of electricity. A source would measure the total mass flow, temperature and pressure of process steam, as well as the enthalpy of the returned and/or make up condensate. A source would then calculate the amount of heat transferred to the process steam and convert it to an “equivalent electric power” based on 3,413 Btu/kWh. This “equivalent output” would be added to the actual electric output.

Sources using a portion of the steam generated to operate process equipment other than electric generators should also convert this work to an equivalent amount of electric power. Since there are no specific instrumentation that can appropriately measure the amount of work performed, it would be calculated from other process parameters. For example, process steam can be used to power pumps, fans, compressors, and similar equipment. In this case, work performed by the equipment can be calculated based on the flow, and inlet and outlet temperatures and pressures of the fluid being transported (not the steam used to power the equipment). This useful work can then be converted to an equivalent amount of electric energy.

Needs for Additional Publicly Available Data

The Energy Information Administration (EIA) withholds some of the electricity generation information it collects from non-utility generators in order to protect source confidentiality. Therefore, part of the generation data required to establish State budgets is not available to EPA. Thus, EPA and States would have difficulty in computing total generation and budgets. EIA solicited comment in a July 17, 1998 Federal Register Notice on a proposal to make electricity generating data non-confidential and publicly available from non-utility electricity generators. If EIA were to keep this information confidential, then EPA and States would need to collect their own data. Output information would only become available if sources report it directly to the Agency or to States through CEMs.

In addition, some units are cogenerators, which are electrical generators that divert part of their heated steam to provide heat steam output, rather than to generate electricity. Information on steam output from cogenerating units or from industrial boilers is not currently available to EPA. A cogeneration unit that was included under the State budget as an electric generating unit based upon heat input would only have its electrical output included in an output-based State budget, ignoring the portion of heat input used to generate steam output. Thus, output-based State budgets based on currently available data could inadvertently under allocate budgets to States with many cogenerators, which are some of the most efficient units. This could actually discourage improvements in efficiency through cogeneration. EPA could decide to make all the required data available as part of CEMs reporting. EPA would have to revise part 75 to monitor and report temperature, pressure, and steam heat output (mmBtu) for units with some or all of their output as heated steam. It will take several years for promulgation of guidance and/or rules, and the acquisition, installation, and testing of equipment. Once the needed equipment is installed, it is necessary to accumulate sufficient data to form a representative baseline. Any consideration of applying an output based allocation process should wait until this baseline can be developed.

For some sources the additional costs for monitoring the energy used for process steam or any mechanical work is not trivial. To install the needed additional instrumentation could be cost prohibitive. Some sources may decide that the cost burden is not worthwhile considering the potential benefits. As a result, they should be allowed to “opt in” to monitoring the portion of their output that goes to process steam or other forms of work.

Summary

There are several technical and administrative issues that must be overcome before output based allowance allocations can be applied. The most pressing would be the need for comparable data across the industry. The collection of data from one standard approach such as CEMs seems to be the most appropriate. To implement changes to CEMs monitoring techniques will take time to implement, and develop baseline information. However this will ensure the best baseline data. In the mean time, there are significant other opportunities and likely more effective methods to achieve the same goals of output based standards. They include utility deregulation and NSR reform. To the extent that output based allocations are eventually adopted, they must include only sources that need them for compliance and do not penalize sources for running pollution control equipment.

Table 1. STATE BUDGETS (TONS PER YEAR) BY ENERGY SOURCE BASIS
(HIGHER OF 1995 OR 1996 EIA DATA)

Column 1 State	*Column 2* Revised Input-based budgets Fossil fuel-burning Generators	*Column 3* Output-based budgets All generation sources	*Column 4* Output-based budgets--All generation sources except nuclear	*Column 5* Output-based Budgets Fossil fuel-burning Generators
Alabama	29026	34832	35068	32744
Connecticut	2583	7677	5156	4456
Delaware	3523	2392	3214	3417
D.C.	207	100	133	142
Georgia	30255	32223	31713	30819
Illinois	32045	44253	27888	29602
Indiana	49020	32212	43285	45831
Kentucky	34923	24847	33389	34166
Maryland	15033	13284	12969	13212
Massachusetts	14780	11017	13248	13496
Michigan	28165	32275	32037	32457
Missouri	23923	19790	22700	23498
New Jersey	10863	12764	11227	11470
New York	30273	39503	39440	32114
North Carolina	31394	32006	30156	29866
Ohio	48468	39790	47143	50019
Pennsylvania	52006	53450	47014	48476
Rhode Island	1118	2242	3012	3202
South Carolina	16290	23252	14085	13831
Tennessee	25386	26410	26084	24770
Virginia	18258	19091	15700	15567
West Virginia	26439	22853	30708	32527
Wisconsin	18029	15745	16637	16324
Total	542007	542007	542007	542007

Table 2. EFFECTIVE EMISSIONS RATES (LB/MMBTU) BY OUTPUT BASIS
(HIGHER OF 1995 OR 1996 EIA DATA)

Column 1	*Column 2*	*Column 3*	*Column 4*	*Column 5*
State	Effective emission rate under Input-based budgets (Fossil fuel burning generators)	Effective emission rate under Output-based budgets All generation	Effective emission rate under Output-based budgets--all generation except nuclear	Effective emission rate under Output-based budgets Fossil fuel-burning Generators
Alabama	0.15	0.18	0.18	0.17
Connecticut	0.15	0.45	0.30	0.26
Delaware	0.15	0.10	0.14	0.15
D.C.	0.15	0.07	0.10	0.10
Georgia	0.15	0.16	0.16	0.15
Illinois	0.15	0.21	0.13	0.14
Indiana	0.15	0.10	0.13	0.14
Kentucky	0.15	0.11	0.14	0.15
Maryland	0.15	0.13	0.13	0.13
Massachusetts	0.15	0.11	0.13	0.14
Michigan	0.15	0.17	0.17	0.17
Missouri	0.15	0.12	0.14	0.15
New Jersey	0.15	0.18	0.16	0.16
New York	0.15	0.20	0.20	0.16
North Carolina	0.15	0.15	0.14	0.14
Ohio	0.15	0.12	0.15	0.15
Pennsylvania	0.15	0.15	0.14	0.14
Rhode Island	0.15	0.30	0.40	0.43
South Carolina	0.15	0.21	0.13	0.13
Tennessee	0.15	0.16	0.15	0.15
Virginia	0.15	0.16	0.13	0.13
West Virginia	0.15	0.13	0.17	0.18
Wisconsin	0.15	0.13	0.14	0.14